STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	)
Summer 2006 Electricity Supply	) Docket No.
and Demand Outlook	) 05-SDO-2
	)
	)

CALIFORNIA ENERGY COMMISSION

HEARING ROOM B

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, DECEMBER 8, 2005

10:05 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

STAFF PRESENT

David Ashuckian

Denny Brown

Albert Belostotsky

Richard Jensen

Jim Woodward

Tom Gorin

Lynn Marshall

ALSO PRESENT

Tom Miller
Pacific Gas and Electric Company

Richard Aslin
Pacific Gas and Electric Company

Tom French
California Independent System Operator

Manuel Alvarez
Southern California Edison Company

via teleconference

Mark Minick
Yanos Kukut
Southern California Edison Company

Bill Tom
Pacific Gas and Electric Company

Mike Mason
CPA

Caroline Keogh
California Energy Markets

I N D E X

P R O C E E D I N G S

10:05 a.m.

MR. ASHUCKIAN: Looks like we're going to have a small crowd today so I think we'll go ahead and get started. I do believe we have some folks on the phone. And in a minute here, why don't we -- I'll just give a brief introduction and we can go around the room and kind of just let everybody know who's on the phone and who's in the room, if that sounds good with you.

We're here to discuss our 2006 summer outlook report. I'm Dave Ashuckian, Manager of the Electricity Analysis Office. With me today is Denny Brown, who's our chief number cruncher for the supply/demand numbers; as well as Albert Belostotsky, who is our probability expert, who will give a presentation on some of the new work we're doing on probability analysis.

If anybody has a problem hearing me, please let me know. We do have a wireless mike system here that we can use, if necessary. But given the small crowd, certainly I think it's appropriate to go forward without that.

Why don't we start off by going around the room, seeing who's on the phone, as well as who's in the audience here so people can have a better understanding of the participants. And then I'll go through some of the introductions to our work.

MR. MILLER: Sure. This is Tom Miller, PG&E.

MR. FRENCH: Tom French from the California ISO.

MR. ASLIN: Rick Aslin, PG&E.

MR. ASHUCKIAN: Okay.

MR. JENSEN: Richard Jensen, Electricity Office.

MR. WOODWARD: Jim Woodward, Electricity Office.

MR. GORIN: Tom Gorin, Demand Office, CEC.

MS. MARSHALL: Lynn Marshall, Demand Office.

MR. ALVAREZ: Manuel Alvarez, Southern California Edison.

MR. ASHUCKIAN: And on the phone?

MR. TOM: Bill Tom with PG&E.

MR. MINICK: Mark Minick and Yanos Kukut (phonetic) from Southern California Edison.

MR. ASHUCKIAN: And is that it, on the phone?

MR. MASON: Mike Mason, CPA.

MS. KEOGH: Caroline Keogh, California Energy Markets.

MR. ASHUCKIAN: Is that it for the phone? Okay. For those of you on the phone we should have there, the slides that we're presenting today should be on our website under the docket for this workshop. So, hopefully all of you have those slides. And our report is also there, that we're discussing.

Just to give you some background, we presented our 2005 outlook back in March of 2005. And at that time we were handling some of the numbers, some of the areas of our outlook a little bit differently than we're now doing. We've made some changes as a result of the comments of that workshop.

Those changes were primarily regarding how we treated plants that were considered at high risk of retirement, as well as the demand response and interruptible programs.

And, again, as a result of comments we received and input from the Energy Action Plan group. We did make some changes, and now we're actually presenting -- what we're presenting is actually three different scenarios.

What we call the planning conventions; these are the same numbers used for resource adequacy planning. We're also presenting what is considered an expected or average outlook. And then we're adding some adverse conditions, what might happen given some of the potential adverse situations that could occur.

And with that we think we provide a much better, a much more broad understanding of what we've procured, what the system is capable of handling, and what potential issues might come up.

We presented our numbers actually in a preliminary meeting at the EAP on September 12th. This was prior to any work with our collaborators, the ISO, PUC and some of the discussions with the utilities.

They asked us to come back with more complete, more vetted numbers. And so that's -- we've done that. And now we're having this opportunity to have comments on that work.

And we're planning to present the results of this, as well as any comments we receive today, at the next EAP meeting, which is scheduled for Monday, this Monday, at the PUC. I think it starts at 1:00.

We've had a number of meetings with the ISO and with PUC Staff. And we have had discussions with some of the various utilities that have issues with some of the numbers we presented last year. And, so, you know, we think we're getting pretty close to agreement on what the outlook looks like.

Today we'll talk about the changes that were made as a result of the comments. We'll also talk about, you know, give you kind of an overview of the tables that have the numbers that we've come up.

And we'll give the first public look at the probability analysis. And one of the things I wanted to point out with this is that we are still trying to gather data on some of the various events that could occur, adverse events that could occur to affect the reliability of the system.

Our probability analysis right now is looking at temperature, loads, variations as a result of temperature, as well as outage data, what the likelihood of outages are.

We've just taken those two parameters and done some probability of what the likelihood is of those two events occurring simultaneously.

And obviously those aren't the only things that can happen to the system, and so we are continuing to try to gather data to expand that methodology.

And, again, this is an opportunity for stakeholders to provide comments and any concerns that they have with what we're doing.

For those of you who are here, obviously you should already know how to participate, but, you know, this slide has the call-in number, as well as the information.

We are accepting written comments. We'd like to have them by December 23rd just so that we can have an end-date for those. And if you'd put docket number 05-SDO-2, that will be recorded to this effort. And it also will get published on our website so other people can see your comments.

Just again a little bit more about the next steps. We do plan on publishing a final outlook. It would be sometime in early spring, probably sometime in March.

We also plan, as I said before, to present this to the EAP on Monday. And we will continue to expand and refine our probability analysis. And as we make significant progress there, we will be presenting that as appropriate as the time goes on.

At this point we haven't presented this to the Commissioners, the EAP group, so you guys are getting a first look at this work.

And with that I'll go and let Denny Brown get into the nitty-gritty details of our presentations today.

Is there any question before we go on from here? All right.

MR. BROWN: Good morning; I'm Denny Brown with the Electricity Analysis Office. As Dave mentioned, we've been working with a lot of the entities in California to refine this data, provide the best outlook we can.

I wanted to thank the cooperation we've gotten from the PUC, the ISO, as well as the investor-owned public utilities.

Just one more administrative note. For those on the conference call, if you have any questions or comments, I'd just like to remind you to state your name and affiliation, as the workshop is being recorded.

Today I'm going to detail some of the

methodology changes we've had since our 2005 outlook and workshop that we had in March. I'll list three caveats that should be associated with these tables. And then I'll review the four outlook regions we've got statewide, the California ISO, North Path 26, and south Path 26.

And finally, I'll just briefly cover a couple of resource assumptions that have been included.

As Dave briefly mentioned, the tables have been broken out into planning conventions, as well as two operating conventions. As we go through the first table I'll kind of highlight how these changes have been implemented.

Another major change we had is we've taken the high-risk retirements out of the calculated portion of the tables, and we've moved them down into line 21 for informational purposes. So they no longer are negatively affecting the operating reserve margins.

We've also included demand response and interruptible programs in lines 7 and 8. These programs are counted, calculated into the planning reserve, as well as the adverse condition reserve. We did not include them in the expected operating reserve as it looks like the reserve margins are fairly robust in those conditions. However, they would be available for contingency operations if something, a factor outside of our tables happened.

We've taken MID, Redding, Roseville, Turlock and Western Area Power Administration out of the north Path 26 tables, as well as out of the ISO tables. Those are still included in the statewide tables.

And finally, as Dave mentioned, we've conducted our initial probability assessment for the SP 26 region.

Some caveats. These tables represent the physical system capabilities. They do not evaluate market conditions or deliverability of contracts. One other risk that is growing daily is they do not evaluate the financial condition of power plant operators.

These tables should not be used in determining resource adequacy of individual utilities within the specified region that the table represents. We may have a power plant physically located in the SP 26 region, but there is nothing preventing that power plant from selling to a utility out of state. So it may or may not be there for an individual utility to contract with.

And then finally we have other factors that are not included in this assessment that can have a major effect on the operation of the system. A good example of that is a major transmission outage such as occurred in August of this year when the DC line dropped and it created a transmission emergency in southern California.

First outlook that I'll go over is the statewide outlook. Here you can see the change in tables. The top third of the table represents the resource adequacy planning convention. And then the planning reserve is highlighted in green. The middle of the table is the expected conditions highlighted in yellow. And finally, adverse conditions highlighted in red, looking at some low probability events that could occur.

You can see on lines 7 and 8 we've included demand response to interruptible programs. And on line 21 is the existing generation without capacity contracts. Again, for informational purposes. And these are power plants that we identified in our 2004 aging power plant study that currently do not have RMR -- I say currently, as of 2004 did not have RMR contracts.

These plants, we believe, are competing for, or may have already secured contracts under the resource adequacy proceedings, but we do not have any public information saying so at this time.

If one of these power plants or several of these power plants do decide to retire, we'll see that portion move up to line 2 as a known retirement. And then it will negatively affect the planning reserve, as well as operating reserve margins of these tables.

Just a summary of the statewide. Traditionally California peaks in August. Reserve margins, under all scenarios, appear robust.

Moving into the ISO control area again, generally peaks in August. However, very little difference between late July into early September. Again, reserve margins under these scenarios appear to be very robust. As you can see, in August 10.5 percent reserve margin under the adverse scenario, when not including demand response or interruptible programs.

Moving into NP-26. This table has changed significantly from what we have previously shown. And the big change on this is going to be under line 4, net interchange.

Historically we have not subtracted out the 3000 megawatts of exported capacity going into the SP-26 region as we were trying to do independent analysis of each region. But based on the fact that the SP-26 region is likely to need the capacity and the ISO controls the flow and the movement of that capacity, we felt that not including it in NP-26 may give an impression of far greater amount of reserves than were actually there.

Even with the 3000 megawatts taken out, we still see a healthy reserve margin under the adverse condition in July; northern California generally peaks in July. Again, it can peak early August.

And finally, moving into the SP-26 region, SP-26 will generally peak late August, early September, although this summer we saw the peak on July 20th.

Under the expected operating conditions reserve margins appear adequate. If we move into adverse conditions you can see there's a 2.8 percent reserve margin without demand response and interruptible programs, so that would trigger stage 2 potentially.

However, the demand response and interruptible programs appear adequate to bring us back up to the minimum operating reliable criteria by WECC.

Significant amount of capacity in southern California that is at risk under the aging power plant study.

Just some individual line items on the resource side. Here's some additions to retirements. You see our major retirement is Mojave. We're counting that at 1320 megawatts.

And then in northern California Hunter's Point I and IV for 219 megawatts.

Looking at the net interchange number, here you can see that we subtracted out the 3000 on Path 26 flowing south. And included in the SP interchange. We've also taken out the MID/TID exports to show that they've moved out of the control area. And so we net northern California 550; net southern California is 10,100.

Now, any of these individual line items

may vary a little bit, but the bottomline shouldn't, as this 10,100 represents -- limitation.

And finally, just a plant-by-plant list of the existing generation that as of 2004 did not have capacity contracts. And, again, we've got 3040 in southern California and 680 representing Pittsburg VII in northern California.

Is there any questions on the 2006 tables?

MR. MINICK: This is Mark Minick from Southern California Edison.

MR. BROWN: Yeah, Mark.

MR. MINICK: If it's possible, could you and the ISO give us the accounting mechanism you're using for Mojave? As I understand Mojave, we are a participant in the ISO and have about 800 megawatts coming in. But this analysis does not appear to be looking at Nevada or southwest, nor LADWP, and they own the rest of that particular plant

Where a 1320 might be a reasonable estimate of the entire plant, it seems like you've taken out more than would be affecting SP-26.

MR. FRENCH: This is Tom French with the

California ISO. I'm not quite sure if I understand the question, but essentially what we've done is we've accounted for Mojave, at least in the way we've gone about doing our forecast we've accounted for Mojave within the control area.

However, we reduced, in putting together the forecast, we reduced the forced outage expectation by a couple hundred megawatts as a result of assessing how Mojave had been operating. That being it wasn't operating at 1500-and-some-odd megawatts, but closer to, I believe, 1300 megawatts on an ongoing basis.

So, in terms of impact on the overall 2006 forecast, we accounted for -- although we show that it's a 1500 megawatt retirement, which it is, we adjust the numbers as we go through the forecasting process to reflect the fact that it was only contributing about 1300 megawatts to the control area.

MR. MINICK: Okay, that's where my question arises. It is not contributing 1300 megawatts to the control area. It is in your control area, I agree. And we schedule, in essence, all the megawatts maybe to the ISO, but we counter-schedule Nevada's portion and Salt River's portion and L.A.'s portion out of the ISO.

So I don't think that capacity was ever really contributing to supporting load in the ISO's control area.

MR. FRENCH: We took that into account, as well. Assuming Mojave goes away, and it was, let's say we were exporting half of the capacity of Mojave, we still need that -- we still account for that by -- the import level, assuming that Mojave goes away, we can get the additional capacity from outside the area.

I'm not sure I'm explaining this right, but the overall import level doesn't change. the net import level that we believe we can get through the various ties in the southern California area overall does not change.

So, even though we had 1500 out, or we had the, let's say half of that going flowing out at the time, we had counter-schedules coming in. Assuming you don't counter-schedule against that, you still have the ability to import into the area, you know, not having a particular counter-schedule there.

So I'm not quite sure if I'm explaining

this correctly, but we did account for that counter-scheduling across the interties, factoring in whether we had Mojave going out or not.

MR. MINICK: Okay, let me try to paraphrase what I think I heard, and you can confirm whether I've heard you correctly.

It sounds like on that net interchange number with Mojave going out as a generator, you're still allowing other energy from outside the area to come in along that path, which could replace Mojave.

MR. FRENCH: That's correct.

MR. MINICK: Okay.

MR. ASHUCKIAN: One of the other factors is that because we used to count Mojave as only the California portion, when we had these discussions with the ISO and bumped that back up, we also bumped up the existing generation number, such that when we take Mojave out we're taking more out -- we put more in, and then we're taking more back out. So the net is zero as a retirement.

So, we're not taking about more than we had put in before, if that makes any sense to you.

MR. MINICK: Sort of, and we may need to

maybe share databases to make sure we're counting everything correctly.

Another question, on the table that you show existing generation without capacity contracts, it's just more of an editorial issue. On the column you say retirement date, I don't think they're necessarily going to retire, so if we could retitle that non-contracted date or something like that, it would make me feel better.

MR. ASHUCKIAN: Okay.

MR. MINICK: Unless somebody's announced a retirement.

MR. ASHUCKIAN: Yeah, no, you're right. Good comment. No, actually I believe that used to say at-risk retirement date.

MR. MINICK: Yeah, --

MR. BROWN: I think when the table -- the table got squeezed down a little bit to -- so we'll correct that.

MR. MINICK: Yeah.

MR. ASHUCKIAN: Yeah, and we'd be happy to accept any information anybody wants to provide that indicates that any of these plants may no longer be a high-risk plant.

MR. MINICK: Well, in some cases, and I

can't reveal much information about Edison, but I do know that some of the people that own these plants do have some contracts that might be considered LD contracts. And they have to have capacity to support those contracts.

So if there's some way to footnote this thing, these resources might be being used for other contractual obligations in a round-about sort of way, that might take some of the pressure off people viewing these are definite, firm possibilities for retirement.

MR. ASHUCKIAN: Okay. Any other questions?

With that I think we'll move into the next section on the probability analysis.

MR. BELOSTOTSKY: I'm Albert Belostotsky (inaudible) Analysis Office. We made probablistic analysis of the adequacy of the power supply for southern California for ISO southern California.

They characterized the assessment of adequacy of power supply at some average conditions. Usually one-in-two conditions. Sometimes the analysis is added by one-in-ten case.

This is all necessary as it assesses

adequacy in most probable cases. But it is not sufficient, as we believe, as multiple other cases are possible which are not covered by this analysis.

So we turn to probablistic approach. In fact, some, if not all, factors are not deterministic. And the examples are weather conditions, which we cannot predict with a point forecast. Availability of resources, forced outages, additions and retirements are all not deterministic, in fact.

So, in (inaudible) case, there are two patterns of uncertainty. If you consider different combinations of possible use of characterizing distractors, we can come across with two different patterns. The some combination of parameters supply meets demand, which as a combination it doesn't.

When we switch to probablistic analysis we actually cannot say for sure that the adequacy of power supply exists or not. We can make judgments only with certain probability. We introduce the term of risk, which is widely spread; and we call risk the probability of inadequate supply, we can risk.

Risk of noncompliance with operational requirements are assessed in this study. And operational requirements are expressed in reserve margins.

Reserve margins are compared with (inaudible) set up targets, reserve margins, which is divided into stage one, stage two, stage three. And we also added the case when we actually have a physical shortage of supply.

Two factors are considered uncertain. All other factors are fixed. Why do we focus on these two factors? Because of their availability of data. Some other considerations can also be made, but we limited our analysis with this to date, two factors, as we know that they are acceptable for all parties that participated in collecting this data and the analysis.

And first of them is probability of load. On this graph probability of load is presented in the form of cumulative probability. And the right side of this graph, which is of special interest, where we have the higher loads than average value, is of special interest for our analysis.

As you can see, the total range of the

change of load is from low 20 -- gigawatts to high 31 gigawatts. Wide, big range. But the highest levels of loads can occur only with very low probability. In this case, somewhere about 1 percent of probability is that we have 31 gigawatts in this region, which means that it might happen once in 100 years.

The second factor is the probability of forced outage. We based this graph and this statistic on the data that we received from ISO. Here you can see that median or average level is about 1 gigawatt. With the lowest somewhere around 200 megawatts and highest level, the level of about 3 gigawatts of outage.

Putting all this together we use the supply adequacy model, or in short, SAM, that the staff developed and used for some time here at the California Energy Commission. And WECC Staff is using for their calculation for western interconnection.

So, in this case, we used supply adequacy model with the two random factors, as I mentioned before.

The cumulative probability of the adequacy is summarized in this graph. It shows that for critical reserve margins of 7 percent, we can come with the probability of 84 percent, or the confidence is 84.1 percent that we cross the 7 percent target. That is 88.7 percent confident that we cross -- we don't cross 5 percent target. And 95 percent that we don't go below 1.5 percent.

The previous graph does not take into account the additional possibility of influencing demand side or the equation. On this graph we show what is the effect of demand response if we take it into account, or also interruptible.

And you can see that the confidence that we don't cross 7 percent reserve margin increases by almost 80 percent -- 4 percent. And in total, this is the area of demand response -- if we also apply interruptible capabilities, then the confidence that we don't cross the 5 percent target is the level of 98 percent. Which means that we will cross -- the probability is that we will cross this target is 2 percent. It may happen once in 50 years.

So, the total result, as we can see here, is that if we apply all resources that are available for us, within the scope of data that was available for us, we can probably -- say that adequacy of supply is at high level of probability.

Thank you.

MR. ASHUCKIAN: I just want to point out again that this is only using the interruptible programs, as well as looking at outages and temperature for load. It does not account for all of the other myriad of things that could happen to the system that could cause outages.

And we're continuing to try to collect data on things like transmission outages, other outages that can have an effect, to continue to make this a more comprehensive analysis.

The purpose of this was to show that for one, just continuing to gather additional generation resources may not be the solution to a more reliable system. That there are other things that can happen.

But looking at this shows that, you know, just having the expectation that generation alone is going to take care of the system is pretty good right now. That adding more generation is just going to continue to get you closer to 100 percent for that particular factor. But it's not necessarily going to make the system more reliable.

MR. ASLIN: I have a question.

MR. ASHUCKIAN: Go ahead. State your name, again.

MR. ASLIN: It's Rick Aslin from PG&E. I thought this was a very interesting analysis, but the question I had was what did you assume for the correlation between high load and forced outages? Did you assume they were independent or --

MR. BELOSTOTSKY: I asked this question several times. We actually tried to find the correlations between forced outages and the level of the load. We did not find this correlation based on the data that we have.

I don't say that there is no correlation; intuitively it should be. But at this point we did not find this correlation.

MR. ASLIN: Okay, so in this analysis it's assumed that they're independent?

MR. BELOSTOTSKY: That there is no correlation.

MR. ASLIN: Okay. Thanks.

MR. ASHUCKIAN: And we are using three years of outage data, not, you know, all outage data for the last 50 years.

Any other questions?

MR. MINICK: This is just a clarifying question. Where you said that the -- this is Mark Minick from Southern California Edison.

You said that these probabilities don't look at probabilities of losing transmission lines. But on the counter side I don't think these probabilities also look at other interruptions that could occur during emergency situations, like state program state water pumping load interruptions or emergency support from other control areas.

Am I clear in saying that?

MR. ASHUCKIAN: Yes.

MR. MINICK: Okay.

MR. ASHUCKIAN: We identified at least ten other factors that could have an effect that we don't have enough data on right now to actually do a quantitative analysis on. That's part of our ongoing work, to try to continue to collect -- to identify those factors and collect data on those.

MR. MINICK: Okay, thank you.

MR. FRENCH: This is Tom French at the California ISO. I did want to point out also that even though we have high loads, we're still operating the system typically under normal ratings, normal system, normal equipment ratings.

We're pushing them typically -- we're pushing those normal equipment ratings in some cases. But unless there's a declared emergency where we actually lose a line, we typically don't even go into -- we wouldn't go into the emergency ratings of equipment.

So that may be why you're not seeing a correlation between high temperatures and high loads and additional forced outages.

Sure, it's stressing the system a little bit more. You may be pushing the normal capability, but you're still running the system within its normal capability typically.

MR. ASHUCKIAN: Well, that's the end of our formal presentation on this. And at this point we offer the utilities and any other stakeholders to provide comments on their analysis, if there are those interested.

MR. MILLER: This is Tom Miller with PG&E and I do have some comments. First, I'd just confirm PG&E did meet with the CEC to review a previous version of the summer of 2000 outlook.

And some of our comments have already been incorporated in the report. And we will continue to work with the CEC Staff to provide load and resource information as needed.

PG&E concurs with the CEC outlook in that the California ISO, northern California reserves are adequate under normal and adverse conditions.

PG&E will have sufficient resources to meet 115 percent of its expected customer peak demand for the summer months of 2006.

I have a few specific comments. First, this is a point that you had covered, and PG&E is pleased that the staff had adjusted the NP-26 net interchange such that 3000 megawatts is exported to SP-26. And as stated in your report, the export reflects the greater need of capacity in SP-26 than in P-26, but it does not imply that is contractually obligated to SP-26. So we support that.

I think it's instructive that you are now presenting both a planning and operating reserve perspectives, and the assumptions and methodologies used to calculate the loads and resources availability and the planning reserve margin should comport with the CPUC-adopted resource adequacy rules.

Examples of deviation in the resource adequacy rules are first, in the one-in-two demand, assuming average growth should be used. And it's unclear why the staff selected the high forecast.

Regarding the demand response and interruptible programs, it is correct to count them as resources. But there should also be credit for these programs towards in defining the reserve requirement needed.

And another example would be the wind capacity should reflect the average production between noon and 6:00 p.m., which is approximately 20 percent of the installed capacity, and not the 3 percent currently used by the CEC.

Regarding the CEC probablistic approach, feel that it needs further evaluation as to the acceptable level of the risk and the costs associated to meet such a planning criteria.

And we will be providing additional written comments and provide them to the staff. So, thank you.

MR. ASHUCKIAN: Thank you. Any other

comments?

MR. FRENCH: This is Tom French at the California ISO. I have a few comments on the report. And, again, I want to thank the staff for working closely with the ISO in the preparation of this particular report.

Generally speaking, well, we've just completed a preliminary forecast, as well, for the summer of 2006. And that forecast generally indicates the same general conclusions as the CEC, that the reserves for the control area as a whole appear to be adequate under most expected conditions.

That the reserves in both NP-26 and SP-26, under most expected conditions, appear to be adequate. And that reserves under adverse conditions in SP-26 are inadequate.

The ISO continues to have a concern about using interruptible programs as part of maintaining minimum reserve requirements. We are required to maintain a 3.5 percent spinning reserve. Converting nonspin and using interruptible programs do pose operating challenges in terms of avoiding firm load shedding, should those adverse conditions materialize.

As a public policy issue in the recent opinion on resource adequacy requirements issued by the CPUC, it does indicate in there that LSEs are required to demonstrate that they have acquired the capacity needed to serve their forecasted retail customer load. And whether interruptible programs and demand response are included in that retail customer load. I'm not sure that that's entirely clear.

It also says in that opinion that we are adopting an RAR in support to spur infrastructure development and assure that capacity is available to the ISO for dispatch. In doing so we are rejecting business as usual, and instead favoring a more robust LSE procurement practices.

And so in that series of sentences I don't know that it's entirely clear that the intent is to try to continue to use interruptible programs and demand response as a mechanism for determining whether operating reserves are adequate within California, or whether interrupting or the use of demand response and interruptible programs will be a business-as-usual in summer months, as part of meeting minimum reserve requirements year after year.

So that's just a general comment. I think there's still some lack of clarity as to what the end objective is in California in terms of using these programs as a means of determining adequate reserve margins in future years.

Just another note. There are some differences in our forecast numbers. We will be issuing our preliminary assessment, be going to our Board on December 15th.

There are some differences in the absolute reserve numbers that are in there; however, again, I want to stress that the general conclusions are still the same in terms of resource adequacy and then, or reserve margin adequacy in the north, the south and both under most expected and adverse conditions.

And, again, I think in looking at the probable events that could occur over the next six months, there's probably more downside than there is upside in terms of improving the outlook, the preliminary outlook for the summer 2006.

I think that concludes my comments.

MR. ASHUCKIAN: Okay, thank you very much. Does anybody else have comments? Anybody on the phone?

MR. MINICK: This is Mark Minick from Edison. We appreciate the efforts that the CEC, in conjunction with the ISO, has done on this particular analysis.

I simply have a question of is the CEC or the ISO going to do a long-range analysis, like in the past. Both of them like five-year looks ahead. And I was just curious whether that's in the planning at all.

MR. ASHUCKIAN: We are not doing a detailed analysis for this effort. We have been asked to do a longer term outlook to the EAP. And we will be presenting a preliminary outlook that just shows reserve margin, similar to what we presented in our statewide and WECC report back in July.

The problem we have is without being able to disclose confidential information, we have very little information on additional plant additions and retirements. And so what we can do is just start from what we have this year, and just show how the demand affects our resources.

We believe it may give a very skewed picture about what the future really holds, because not all the information is really disclosable.

So we will show that, you know, if nothing were to change, this is what would happen as demand increases. But it really is not, you know, the same level of complexity as what we have for this next summer.

MR. MINICK: Were you thinking about doing multiple scenarios of "what-ifs" for example? There are a couple of plants that might occur in 2008 that you've licensed, and you could put them in in one case and leave them out in another case.

MR. ASHUCKIAN: Okay, we could do that. And we'll consider that. Actually in our report we did do a scenario of what would happen if plants retire --

MR. MINICK: Right.

MR. ASHUCKIAN: -- as an alternative case. But we could do some scenario --

MR. MINICK: Yeah, and I'd be glad to help work with you to the extent that I can add any value to that analysis.

MR. ASHUCKIAN: Thank you.

Any other comments? Well, with that, I

guess this workshop is at a close.

(Whereupon, at 10:53 a.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Staff Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 9th day of December, 2005.